

Public Service Commission of Wisconsin

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Public Service Commission of Wisconsin
RECEIVED: 12/18/2020 10:41:13 AM

December 18, 2020

Re: Investigation of Parallel Generation Purchase Rates

5-EI-157

Comments Due:

Friday, January 8, 2021 – Noon

This docket uses the Electronic Records Filing system (ERF).

Address Comments To:

Steffany Powell Coker
Public Service Commission
P.O. Box 7854
Madison, WI 53707-7854

To Interested Participants:

On June 11, 2020 the Public Service Commission of Wisconsin (Commission) issued a Notice of Investigation to consider parallel generation purchase rates. The enclosed memorandum draws on comments received from stakeholders, presents Commission staff's review of existing parallel generation purchase rates in Wisconsin, and provides engineering and economic analysis of methods for determining avoided energy and capacity costs associated with parallel generation.

The Commission now seeks comments on the following procedural and substantive questions:


1. Should the Commission order all utilities, or a subset of utilities, to address the comments and analysis presented in this investigation in their next rate filing?
2. Should the Commission commence a proceeding to address the parallel generation purchase rates of any utilities at this time?
3. Of the issues addressed in this memorandum, which issues are best addressed through continued statewide analysis conducted as part of this investigation?
4. Do existing purchase rates for energy and capacity accurately reflect the avoided costs associated with parallel generation facilities?
5. Should additional avoided costs be included in purchase rates?
6. Should purchase rates and terms be consistent across utilities?
7. Should parallel generation resources receive purchase rates and terms equivalent to those associated with utility projects?
8. How can purchase rates be set to appropriately allocate costs among customers?

Comments must be received by 12:00 p.m. on Friday, January 8, 2021. Please limit the length of submitted comments to no more than 10 pages in total. Party comments must be filed using the Commission's ERF system. The ERF system can be accessed through the Public Service Commission's web site at <http://psc.wi.gov>. Members of the public may file comments using the ERF system or by mail at the Public Service Commission, 4822 Madison Yards Way, P.O. Box 7854, Madison, WI 53707-7854. You can also contact Commission Records Management staff at (608) 261-8521 or PSCRecordsMail@wisconsin.gov for assistance.

To Interested Participants
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Please direct questions about this docket or requests for additional accommodations for the disabled to the Commission's docket coordinator, Joe Fontaine, at (608) 266-0910 or Joe.Fontaine@wisconsin.gov.

Sincerely,

A handwritten signature in black ink that reads "Martin R. Day". The signature is written in a cursive style with a large, stylized 'M' and 'D'.

Martin R. Day
Administrator
Division of Energy Regulation and Analysis

MRD:JF:cmb:DL: 01774030

Attachments

PUBLIC SERVICE COMMISSION OF WISCONSIN

Memorandum

December 18, 2020

FOR COMMISSION INFORMATION

TO: The Commission

FROM: Martin R. Day, Administrator
Sherry Colstad, Bureau Director, Rates and Finance
Randel Pilo, Director, Office of Regional Markets
Joe Fontaine, Policy Advisor
Enrique Bacalao, Chief Economist
Akanksha Craft, Public Service Engineer
Ryan Kohler, Regional Energy Markets Policy Analyst
Andrew Kell, Public Utility Rates Analyst
Tyler Meulemans, Public Utility Rates Analyst

RE: Investigation of Parallel Generation Purchase Rates

5-EI-157

This memorandum summarizes and analyzes existing parallel generation purchase rates in Wisconsin and defines key issues to be considered as the investigation proceeds. Two appendices provide detailed staff analysis of the economic and engineering considerations related to the determination of purchase rates. To maintain a stakeholder-driven approach, the Commission requests comments on a new set of procedural and substantive questions as the next step in this investigation, and encourages commenters to use the memorandum and appendices as resources for developing their responses.

Introduction

On June 11, 2020 the Commission issued a Notice of Investigation to consider parallel generation purchase rates. ([PSC REF#: 391581](#).) The investigation was initiated through the Commission's Order in docket 6690-CC-223720, which opened an investigation to broadly

examine the treatment of utility avoided energy and capacity costs, including in parallel generation tariffs and purchase rates for qualifying facilities.¹ ([PSC REF#: 390868](#).)

The Notice of Investigation designated all electric utilities as parties to this docket. ([PSC REF#: 391581](#) at 3.) In its Order of July 27, 2020 ([PSC REF#: 394344](#)), the Commission approved seven additional requests for intervention.² The Order stated that future requests for intervention would be granted without further order, absent objection from existing parties. Five additional requests for intervention have since been granted without objection.³

The Notice of Investigation requested comments on four questions soliciting initial feedback related to the appropriate methods and factors informing the determination of avoided costs, ongoing or anticipated changes relevant to the investigation, and the effects of parallel purchase rates on electricity consumers and producers. ([PSC REF#: 391581](#) at 2.) The Commission received 29 responses, from 5 utility representatives, 7 organizations, and 17 members of the public.

On July 9, 2020 the Commission issued a data request to all electric utilities for information on their parallel generation purchase rates. ([PSC REF#: 393351](#).) The data request:

- solicited information on each utility's existing parallel generation tariff rates and structures;
- asked each utility to explain the most important considerations involved in determining those rates and structures; and

¹ Commissioner Nowak dissented from the Commission's decision to open a generic docket in 6690-CC-223720, and from the issuance of the Notice of Investigation in docket 5-EI-157.

² The City of Milwaukee ([PSC REF#: 392477](#)); Clean Wisconsin ([PSC REF#: 392672](#)); Municipal Electric Utilities of Wisconsin ([PSC REF#: 393515](#)); RENEW Wisconsin ([PSC REF#: 392357](#)); J. David Stanfield ([PSC REF#: 392954](#)); the Environmental Law and Policy Center and Vote Solar ([PSC REF#: 392713](#)); and Tomahawk Power and Pulp Company ([PSC REF#: 392715](#)).

³ The Citizens Utility Board of Wisconsin ([PSC REF#: 394186](#)); Save Our Unique Lands of Wisconsin ([PSC REF#: 394420](#)); Chris Klopp ([PSC REF#: 394635](#)); Wisconsin Industrial Energy Group ([PSC REF#: 394970](#)); and Blake K. Baxter ([PSC REF#: 395032](#)).

- requested the information related to avoided costs that utilities are required to maintain under the federal Public Utility Regulatory Policies Act of 1978 (PURPA), including estimated energy and capacity costs and the utility's plans for capacity additions, retirements, and purchases during the succeeding 10 years.⁴

The Commission received responses from 12 organizations, including 9 individual utilities and 3 entities representing an additional 61 municipal utilities.⁵

For this memorandum, Commission staff reviewed all comments and data request responses, in conjunction with existing tariffs and other available information, to provide an informational summary of existing parallel generation purchase rates in Wisconsin.

Distributed Generation in Wisconsin

Distributed generation resources can provide customers with small-scale generation that provides electricity on-site, in place of electricity traditionally purchased from electric utilities.⁶ Consistent with trends nationwide, the number of distributed generation systems in Wisconsin has grown substantially over the past 10 years. As shown in Figure 1, data reported for the Commission's Strategic Energy Assessment indicate that total distributed generation installations in Wisconsin increased more than tenfold between 2008 and 2019, primarily driven by increased installation of solar photovoltaic (PV) generation systems. This growth has been influenced by a number of factors, including ongoing cost declines for solar PV and other distributed generation

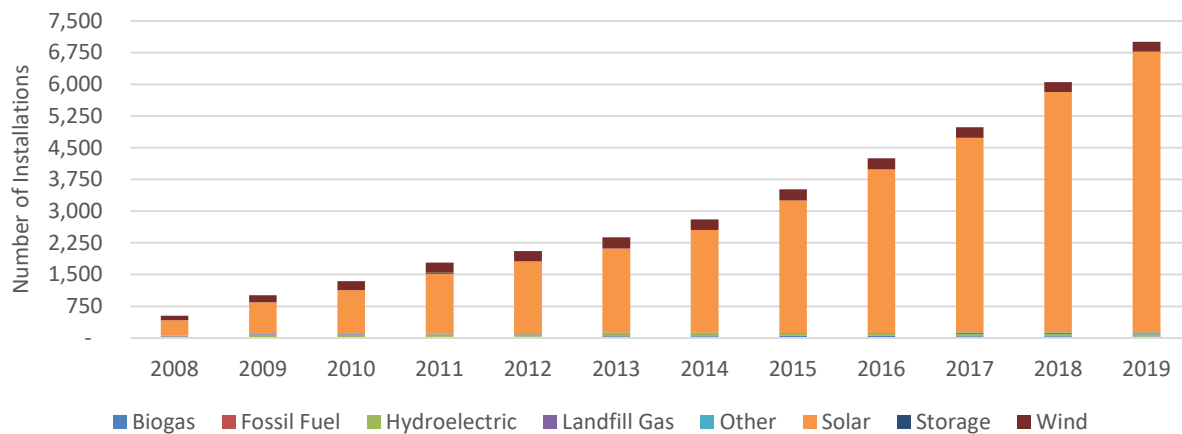
⁴ Per 18 CFR 292.302(b).

⁵ WPPI Energy responded on behalf of its 41 Wisconsin member utilities; Great Lakes Utilities responded on behalf of 10 utilities; and the Upper Midwest Municipal Energy Group responded on behalf of 10 utilities.

⁶ Wis. Stat. § 196.496(1) defines distributed generation facilities as facilities with a capacity of no more than 15 megawatts (MW) that is located near the point where the electricity will be used or is in a location that will support the functioning of the electric power distributed grid.

resources, as well as increased customer interest in controlling their own energy use and deploying zero-carbon distributed generation to achieve reduced emissions.

Figure 1 Number of Distributed Generation Installations by Technology



Distributed generation systems owned by customers are often called customer-owned generation systems (COGS). In addition to providing on-site electricity to customers, COGS can also generate excess energy in amounts greater than the customer’s consumption needs. Systems interconnected to the utility distribution grid direct this excess energy onto the grid, providing additional electric generation resources to the serving utility. Utilities offer specific parallel generation tariffs for COGS, which include purchase rates (sometimes termed “buyback rates”) identifying the unit cost the utility will pay the customer for the excess energy provided.

As the deployment of distributed generation resources continues to increase, the economic significance of purchase rates increases as well. For installers and potential customers, the purchase rate is a significant factor in quantifying the total economic benefits provided by a system, and can thereby influence decisions on whether to procure a system or the size of the system to be installed. For utilities, the growth in parallel generation customers increases the financial impact of purchase rates on their operations, which can in turn influence the allocation of costs through customer rates.

Parallel Generation Tariffs in Wisconsin

Utilities in Wisconsin maintain separate parallel generation tariffs for smaller and larger systems. Small investor-owned utilities (IOU) and municipal utilities commonly set separate tariffs for systems with capacity of 20 kilowatts (kW) and less, and tariffs for systems with capacity of greater than 20 kW. Tariffs are commonly labeled PGS-1 for smaller systems, and PGS-2 for larger systems. As shown in Table 1, Wisconsin's five largest IOUs also maintain size distinctions, but use different tariff names and in some cases set different size thresholds. While Wisconsin Public Service Corporation (WPSC) and Wisconsin Power and Light (WP&L) use a 20 kW threshold for distinguishing small systems and large systems, Madison Gas and Electric Company (MGE) and Northern States Power-Wisconsin (NSPW) use a 100 kW threshold, and Wisconsin Electric Power Company (WEPCO) uses a 300 kW threshold.

Table 1 Tariffs for Smaller COGS at Large IOUs

IOU	Tariff Name	Maximum Size (kW)
MGE	Pg-2	100 kW
NSPW	Pg-1	100 kW
WPSC	Pg-4	20 kW
WEPCO	CGS-NM	300 kW
WP&L	PgS-3	20 kW

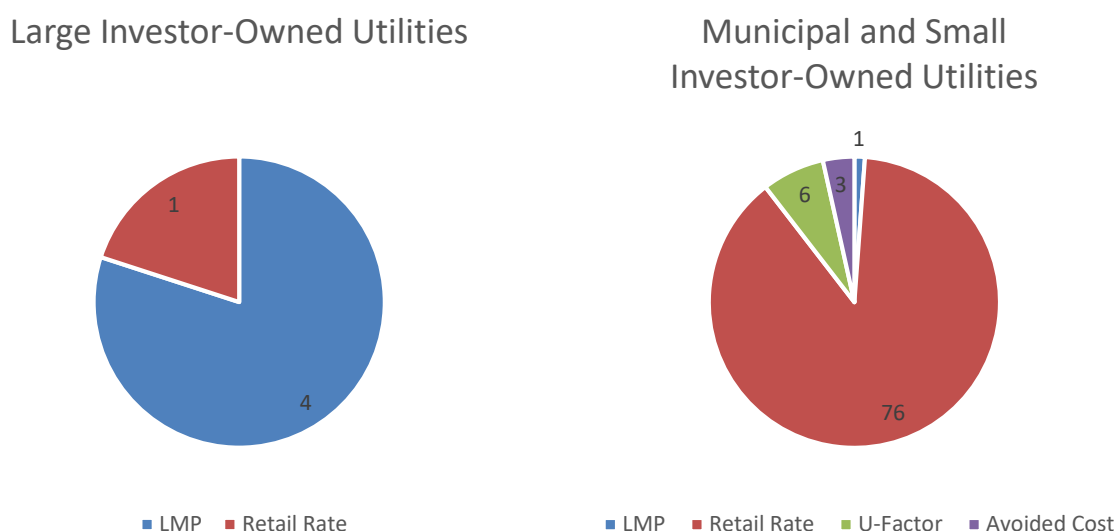
Tariffs for Smaller Systems: Net Energy Billing

Tariffs for small COGS are often labeled as “net metering” or “net energy billing” tariffs. While definitions of net metering can vary, for purposes of this investigation, net metering arrangements will be defined based on the practices used to determine whether COGS produce excess energy subject to purchase rates. Utilities’ net metering tariffs commonly use a “monthly netting” calculation method, under which the total monthly amount of generation produced by a customer’s system is compared against the total monthly consumption by the customer. All

generation at or below the consumption levels is credited at the retail electric rate the customer would pay to purchase the same amount of energy. In practice, monthly netting can allow customers on these tariffs to receive value equal to the retail rate for much, and potentially all, of the energy produced by their system.

For months in which the generation exceeds the customer's consumption, the customer's energy usage is reduced to zero and the utility pays the customer a purchase rate for the excess energy generated. In many cases these purchase rates are also set at the customer's retail rate, but, as shown in Figure 2, there is some variation in this practice across utilities.

Figure 2 Buy-back Rates for Net Energy Billing Tariffs



More than 90 percent of municipal and small IOUs, as well as one of the five largest IOUs, currently offer excess generation purchase rates equal to the retail rate.⁷ By contrast, four large IOUs and one municipal utility offer excess generation purchase rates at the Midcontinent Independent System Operator, Inc. (MISO) Locational Marginal Pricing (LMP), while five municipal utilities and one small IOU offer excess generation purchase rates equal to that

⁷ If a customer takes service under the optional Time-of-Day rate offered by many utilities, they would avoid the on-peak or off-peak energy charge depending on the time of generation.

utility's U-factor, which is also called the base cost of power.⁸ Additionally, three municipal utilities offer purchase rates that are set equal to that utility's avoided cost established through their contractual arrangements for purchasing electricity from their wholesale provider.⁹ In most though not all cases, utilities that do not refer to the retail rate use the same source they use to set purchase rates for larger systems.

Generally speaking, those customers who receive a buyback rate equal to their retail rate receive the highest purchase rates for excess generation. Municipal utility and small IOU rates set based on the U-factor are typically lower than the retail rate but higher than those based on wholesale avoided costs. Rates based on locational marginal prices, which are described further in the following section, offer the lowest purchase rate values. Table 2 below shows that the buyback rates for excess generation under utility net energy billing tariffs can vary between just below three cents per kilowatt-hour (kWh) and just above ten cents per kWh.

⁸ The U-factor is calculated by taking a utility's total cost associated with procuring and generating energy, and dividing that cost by the total retail kWh sales of that utility. The U-factor is stated in the utility's Power Cost Adjustment Clause (PCAC) tariff sheet, and updated during every rate case.

⁹ For purposes of this memorandum, utilities were categorized based on the primary source used to derive their Commission-approved purchase rates. There is some variation in the methods individual utilities use to establish rates based on LMPs, U-factor, and avoided costs that is specified in each utility's tariff language.

Table 2 Net Energy Billing Excess Buyback Rate Utility Examples

Utility	Tariff Name	Methodology	Residential Customer Purchase Rate (\$/kWh Excess Generation)
WP&L	PgS-3	LMP	\$0.0292
WEPCO	CGS-NM	LMP	\$0.04245
Northwestern Electric Power Company	Pgs-1	U-Factor	\$0.0597 ⁺
Superior Water, Light and Power Company	COGS-NM	Pre-determined (similar to U-Factor)	\$0.0606 ⁺
Wisconsin Rapids	Pgs-1	Avoided Cost (similar to U-Factor)	\$0.0627 [#]
Sturgeon Bay Utilities	Pgs-1	Retail Rate	\$0.1060 ⁺

⁺Subject to PCAC adjustments

[#]Updated annually

Tariffs for Larger COGS

All utilities, with the exception of one municipal utility and two small IOUs, offer at least one distinct tariff for larger COGS with capacity above the threshold set for their net energy billing tariffs. Generally speaking, larger COGS will produce excess generation above the customer's consumption more frequently than smaller COGS. This reflects the larger size of the system, as well as the fact that larger tariffs generally offer netting based on metering intervals, which are often on an hourly basis rather than the monthly basis provided under net energy billing.¹⁰

PURPA and Its Effect on Wisconsin Policies

Determination of purchase rates for larger COGS are informed by PURPA, which requires utilities to purchase power from generators interconnected with their distribution systems. PURPA specifically defines a class of “qualifying facilities” (QFs), which could

¹⁰ While this characterizes the general trend, there can be many exceptions based on the circumstances of individual customers. A small system may still regularly produce excess generation for a residential customer during summer months, and a larger system would never produce excess generation for a commercial or industrial customer whose overall usage consistently remains higher than the capacity of their COGS.

include any “small power production facility” that has capacity of greater than 1 MW (1000 kW) and less than 80 MW, uses renewable resources (including biomass, waste, and geothermal) as a generating source, and obtains appropriate certifications.¹¹

PURPA requires utilities to purchase at rates equal to “the incremental cost to the electric utility of electric energy or capacity or both which, *but for* the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.” (Emphasis added.)¹² This definition is commonly referred to as the avoided cost. The generally acknowledged purpose of setting an appropriate avoided cost is to create indifference for the utility regarding the source from which it purchases energy and capacity. In principle, an avoided cost set consistent with PURPA’s definition would leave a utility with equal costs for purchasing distributed generation or procuring the same resources through their own resources or wholesale markets.

PURPA also required state commissions to establish purchase rates for each utility based on the utility’s avoided cost. To implement PURPA, the Commission established policy for calculating avoided costs in its June 23, 1983 Orders in dockets 05-ER-11, 05-ER-12, and 05-ER-13. Under PURPA and the Commission’s Orders, the utilities had a mandatory requirement to purchase capacity and energy from COGS under a variety of conditions.¹³

¹¹ PURPA also establishes a separate QF category for cogeneration facilities of any size that produce thermal energy, such as steam or heat, in addition to their energy output. This paper will focus on small power production facilities, because they are more common and several of the PURPA-related changes below specifically apply only to QFs that are small power production facilities.

¹² See 18 CFR 292.101(b)(6).

¹³ Under the Commission’s integrated resource planning processes, which were in place until 1998, the Commission addressed larger blocks of power of QF or cogeneration capacity identified in resource plans through a two-stage Certificate of Public Convenience and Necessity (CPCN) approach in which during the first phase a competitive request for proposal process was used to establish the terms of the capacity and energy payments. A successful bidder would then go on to establish a purchased power agreement with the respective utility. The second step would then be the ordinary CPCN docket.

The Energy Policy Act of 2005 (EPACT 2005) eliminated many of these mandatory purchase requirements for large systems with capacity of greater than 20 MW, as long as the affected generation had access to an energy market operated by a Regional Transmission Organization (RTO), including MISO, which serves that role in Wisconsin.¹⁴ EPACT 2005 also established the LMPs in an RTO's energy market as appropriate market-based proxies for determining avoided energy costs. LMPs provide location-specific wholesale market prices for energy, which take into account available generation as well as the transmission and grid operation considerations that influence the amount of energy available at each specific location on the grid. Starting in 2009, the Commission began authorizing standard purchase rates for large IOUs based on, or directly tied to, average MISO market LMPs faced by each utility.

In July 2020 the Federal Energy Regulatory Commission (FERC) issued Order No. 872, which made additional changes to PURPA implementation intended to provide state utility regulators with additional flexibility to set buyback rates based on LMPs.¹⁵ Generally, the rule allows states other options for more flexible energy rates, including setting varying rates for the life of a contract or fixed rates based on projected energy prices. Order 872 also allows states to

¹⁴ "Energy Policy Act 2005 Fact Sheet," Federal Energy Regulatory Commission, August 8, 2006. Specifically, EPACT 2005 amended PURPA to remove utilities' mandatory purchase obligation for most QFs larger than 20 MW if they have nondiscriminatory access to competitive wholesale electricity markets. However, the mandatory purchase obligation remained with respect to QFs smaller than 20 MW. In practice the use of energy market LMPs became dispositive for the setting of avoided energy costs across most types of generation sources facing a buyback rates setting.

¹⁵ See FERC Order No. 872, Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, under Docket RM19-15-000, <https://elibrary.ferc.gov/eLibrary/filedownload?fileid=15586408>.

eliminate mandatory purchase requirements for all systems of greater than 5 MW, reduced from the 20 MW threshold set in EPACT 2005.^{16, 17}

Utility Tariffs for Larger COGS

As noted above, utility tariffs for larger COGS' purchase rates differ, and are typically lower than the retail-rate based net metering arrangements more common for smaller systems. As shown in Figure 3, municipal utilities typically purchase their energy through fixed contracts with wholesale providers. Accordingly, 72 of 81 municipal utilities and one small IOU define their avoided costs based on the rates paid to their wholesale supplier. For wholesale suppliers that procure energy from the MISO regional market, such as WPPI Energy, these wholesale rates equate to the LMPs faced by that supplier.¹⁸ One municipal utility sets rates based on LMPs, while four small IOUs and six municipal utilities set rates based on their base cost of power (U-factor).¹⁹

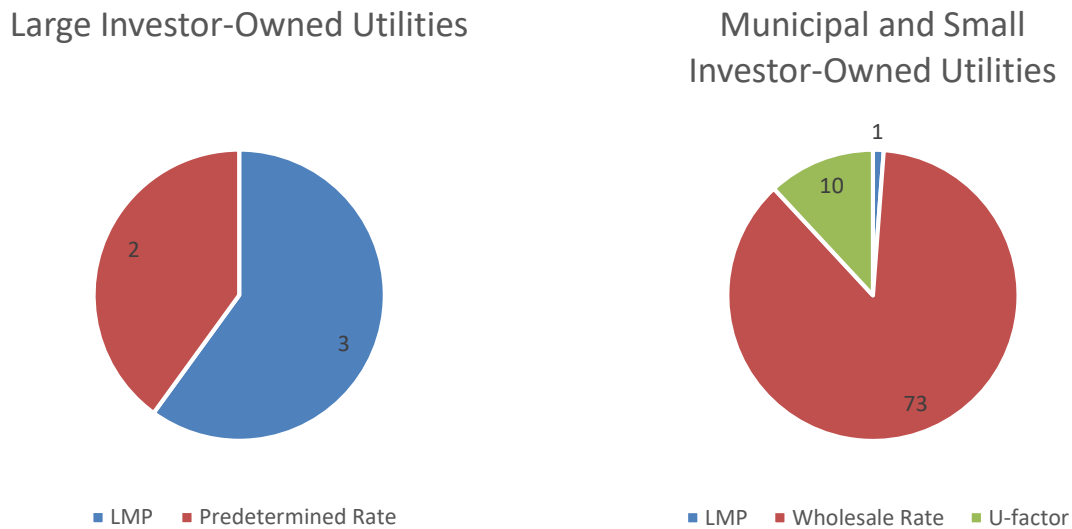
¹⁶ See *Ibid.* at 640. FERC Order 872 affirms that small power production facilities can rebut the presumption of nondiscriminatory access to markets, and particularly identifies an inexhaustible list of factors that could be considered when making such an assessment.

¹⁷ FERC issued a follow-up decision in November 2020 that largely sustained Order 872 and provided limited clarifications to certain changes in the order. See FERC Order No. 872-A, Order Addressing Arguments Raised on Rehearing and Clarifying Prior Order in Part Qualifying Facility Rates and Requirements etc. under Docket RM19-15-001, <https://elibrary.ferc.gov/eLibrary/filedownload?fileid=15662892>.

¹⁸ For the period October 1, 2019 to September 30, 2020 the average real-time MISO LMP was equal to \$21.10 per megawatt-hour. See MISO's "Informational Forum Presentation," October 19, 2020.

¹⁹ For purposes of this memorandum, utilities were categorized based on the primary source used to derive their Commission-approved purchase rates. There is some variation in the methods individual utilities use to establish rates that is specified in each utility's tariff language.

Figure 3 Buy-back Rate for Larger COGS Tariffs



Three of Wisconsin’s five large IOUs set purchase rates that are tied directly to MISO LMPs, consistent with PURPA’s presumption that LMPs can serve as an appropriate avoided energy cost proxy for utilities with access to regional wholesale markets. The other two have pre-determined rates approved by the Commission, both of which offer a higher buyback rate than if they were tied to the MISO LMP, but less than if they were tied to the retail rate.

In addition to energy-based purchase rates, large IOUs may also include a separate capacity-based purchase rate in their PGS-2 tariffs.²⁰ As shown in Table 2, four of the five large generation-owning IOUs offer capacity values, in all cases based on the value of capacity derived from MISO’s annual Planning Reserve Auction (PRA) for procurement of capacity resources. In April 2020, MISO conducted its PRA, and the associated value for the pricing zones affecting Wisconsin was \$5.00/MW-Day.²¹ Rather than making these capacity payments on a per-day basis, IOUs typically levelize these payments in terms of \$/kWh of on-peak

²⁰ As owners of large-scale generation, Wisconsin’s large IOUs are load-serving entities (LSEs) within the MISO region that are responsible for maintaining sufficient capacity to meet projected demand.

²¹ See “MISO-2020/2021 Planning Reserve Auction (PRA) Results,” April 14, 2020. Two pricing zones, LRZ 1 and LRZ 2, affect Wisconsin; both had the same values in the April 2020 auction.

generation. This method results in a small additional payment relative to the purchase rate for energy. For example, WPSC’s PG-2A tariff lists the capacity payment at \$0.00047/kWh, and WP&L rounds the on-peak payment down to zero due to decimal places.

Table 2 Wisconsin IOU Parallel Generation Tariff Capacity Value

IOU	Capacity Value Reference
MGE	MISO PRA
NSPW	MISO PRA
WEPCO	None
WPSC	MISO PRA
WP&L	MISO PRA

The MISO PRA is often considered a short-term procurement or sales opportunity for utilities. This MISO capacity auction is not mandatory for utilities to participate in, as vertically-integrated utilities can opt-out if they can demonstrate to MISO that their planning reserve margin requirements during a summer peak event will be fulfilled by generating capacity owned or under contract. In contrast to the MISO energy market, which is mandatory for utilities interconnected with the MISO grid, the MISO PRA price clearing results are not reflective of a comprehensive supply and demand market interaction. In short, MISO PRA prices are more reflective of a voluntary market with limited participation due to the opt-out option.

PURPA generally only requires a capacity payment if a utility has a capacity need over a foreseeable planning horizon.²² Utilities that seek to demonstrate a capacity need ordinarily can propose to develop or procure a specific generation asset, and then compare the economics of the

²² See page 15 of the NARUC-sponsored 2014 report titled “PURPA Title II Compliance Manual”: <https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC>.

proposal against alternative avoided cost capacity options. One generic capacity value that utilities cite for this purpose is the MISO-determined Cost of New Entry (CONE), which is the capital cost for a new generation resource that fulfills a capacity need at MISO's regional level. In 2020, MISO has set the CONE value at \$257.53/MW-Day.²³

Utilities characterize CONE as more representative of a long-term capacity reference appropriate for their capacity addition proposals, and state that the lower PRA values are more representative of a short-term capacity reference.²⁴ Multiple utility data request responses also stated that the use of PRA values for purchase rates is appropriate due to the "as available" nature of their tariff arrangements with COGS. Utilities stated that existing as-available arrangements do not provide them the control over resource dispatch, outage coordination, or other methods to maintain reliability that they maintain for utility-owned or contractually-committed capacity. Responses added that PURPA identifies those capabilities as appropriate considerations to consider in the determination of avoided costs, and specified that these limitations do not allow them to use COGS to meet MISO capacity obligations.²⁵

While most utility tariffs only offer purchase rates for energy and capacity, a small number of utilities do offer additional credit for avoided transmission costs. Manitowoc Public Utilities offers a \$0.0085 transmission credit per kWh for on-peak generation in its Pgs-2 tariff. WPSC offers a transmission credit of \$0.00831/kWh only on its net energy billing tariff. No utilities currently make payments for values other than energy, capacity, and transmission.

²³ See "MISO-2020/2021 Planning Reserve Auction (PRA) Results," April 14, 2020.

²⁴ See data request responses in this investigation from WEPCO ([PSC REF#: 395553](#)), WPSC ([PSC REF#: 395554](#)), and WP&L ([PSC REF#: 395495](#) confidential, [PSC REF#: 395496](#) public).

²⁵ See comments and data request responses in this investigation from the Wisconsin Utilities Association ([PSC REF#: 393578](#)); WEPCO and WPSC ([PSC REF#: 395554](#)); WPPI Energy ([PSC REF#: 395545](#)); and WP&L ([PSC REF#: 395495](#) confidential, [PSC REF#: 395496](#) public).

Other Tariffs for Larger Systems

In addition to the avoided-cost-based tariffs described above, some utilities offer additional tariff options for larger COGS.

NSPW and WPSC, as well as a number of municipal utilities, offer negotiated rate tariffs that provide COGS owners the option to seek an agreement to set different purchase rates than the standard tariffs. All utilities responding to the data request reported very low participation in this rate option. NSPW and WEPCO also both offer tariffs for COGS owners who do not intend to sell electricity to the utility, while MGE has received approval for a new tariff open to customers who intend only to sell electricity to the utility and not maintain generation for their own use. MGE's tariff offers capacity purchase rates based on CONE, which the utility attributes to the fact that its tariff requirements will allow it to use participating systems as accredited capacity that can help it meet its MISO capacity obligations.

NSPW, WPSC, and WEPCO offer tariffs that offset the energy purchase rate based on live pricing set at the day-ahead LMP value, rather than the historical average LMPs used for standard purchase rates. Under this tariff, customers do not receive a constant or consistent price for their excess generation, as the day-ahead LMP changes hourly. While this type of purchase rate could be challenging for some customers, those who have a higher level of control over the timing of their energy dispatch may be able to see additional benefits from this rate if they can align their excess generation with particularly high day-ahead LMPs.

Initial Conclusions and Next Steps

The above summary of existing parallel generation purchase rates in Wisconsin provides an informational foundation for this investigation. Consistent with the Commission's stakeholder-driven approach to generic investigations, the commenter perspectives offered on

those purchase rates, in responses to the Notice of Investigation and the utility data request, can inform the Commission's approach as the investigation proceeds.

Five leading questions emerge from the stakeholder input provided to-date, largely but not exclusively focused on the avoided cost-based purchase rates in place for larger facilities.

1. **Do existing purchase rates for energy and capacity accurately reflect the avoided costs from distributed generation facilities?** Some commenters characterized existing avoided cost rates as consistent with the costs actually avoided by utilities, and supported existing calculation methodologies as reasonable approaches to efficiently and transparently determining cost values. Others expressed concern that existing rates, particularly for capacity, do not adequately reflect the value being provided by established generation resources or offer appropriate cost signals for future entry of new installations.

2. **Should additional avoided costs be included in purchase rates?** Some commenters proposed that purchase rates should be expanded beyond energy and capacity to more consistently incorporate transmission costs, and/or to account for the environmental benefits associated with the installation of zero-emission generation. Other commenters stated that existing energy- and capacity-focused rates accurately capture the costs actually avoided by a utility, and raised concerns that adding other costs would not be consistent with PURPA and could result in cross-subsidization by other ratepayers.

3. **Should purchase rates and terms be consistent across utilities?** Some commenters stated that different purchase rates, as well as other tariff differences such as the capacity thresholds for net energy billing tariffs, create barriers to distributed generation installation by creating confusion and making it more difficult for installers to

effectively operate across multiple service territories. Other commenters highlighted variations in avoided costs based on differing utility conditions, and some expressed interest in exploring the establishment of different purchase rates by technology.

4. **Should parallel generation resources receive purchase rates and terms equivalent to those associated with utility projects?** Some commenters objected to the presence of differences between customer tariffs and the rates and arrangements established for utility-sponsored projects using the same technologies. Those commenters emphasized that utility projects have been able to receive higher effective compensation than provided by existing customer purchase rates, and contended that distributed generation owners should be able to receive comparable rates and be able secure long-term contract arrangements consistent with the fixed compensation provided for approved utility installations. Other commenters noted the potential for cost differences between installations of different sizes, and stated that existing arrangements limit the ability for utilities to count distributed generation towards capacity obligations (and thereby avoid capacity-related costs).

5. **How can purchase rates be set to appropriately allocate costs among customers?** Each of the avoided cost-related questions above can be construed as relevant to this general issue. In addition, commenters raised cost allocation considerations related to net energy billing arrangements. Some commenters stated that paying distributed generation owners at the retail rate shifts costs to customers that do not own distributed generation. Those commenters noted that the magnitude of these allocation concerns has historically remained limited due to the relatively small number of participating facilities, but would grow in significance with a larger number of deployments or broadened eligibility for net metering tariffs. Other commenters

supported the continuation and expansion of net energy billing arrangements to support interested customers and reap the environmental benefits of increased deployment.

Further investigation of these five questions can help define more specific action options for the Commission to consider under this docket. To expedite this effort, Commission staff has already gathered additional information and analysis relevant to exploring the determination of avoided cost-based purchase rates. Appendix A outlines engineering factors relevant to defining avoided costs, including an analysis of existing methods used to define and value avoided energy and capacity in Wisconsin. Appendix B outlines economic considerations associated with determination of parallel generation purchase rates, including a survey of different methods available for defining avoided cost values.

To continue its stakeholder-driven approach to the investigation, the Commission requests further comments on the five questions outlined above, as well as three additional questions:

- Should the Commission order all utilities, or a subset of utilities, to address the comments and analysis presented in this investigation in their next rate filing?
- Should the Commission commence a proceeding to address the parallel generation purchase rates of any utilities at this time?
- Of the issues addressed in this memorandum, which issues are best addressed through continued statewide analysis conducted as part of this investigation?

Commenters are encouraged to utilize the information provided in this memorandum and the economic and engineering appendices as a resource to develop answers to all questions.

JF:cmb:DL: 01773782

Attachments

Key Background Documents

[Notice of Investigation Signed and Served 6/11/2020 - PSC REF#: 391581](#)

[Final Decision - PSC REF#: 390868](#)

[Order on Requests for Intervention Served 07/27/2020 - PSC REF#: 394344](#)

[Initial Utility Data Request - PSC REF#: 393351](#)

[City of Milwaukee's motion to intervene - PSC REF#: 392477](#)

[Clean Wisconsin's Request for Full Party Status - PSC REF#: 392672](#)

[Late Filed Motion to Intervene and Notice of Appearance of Municipal Electric Utilities of Wisconsin - PSC REF#: 393515](#)

[Request - Full Party Status - PSC REF#: 392357](#)

[Request of Stanfield for intervenor status - PSC REF#: 392954](#)

[Request to Intervene and Notice of Appearance of the Environmental Law & Policy Center and Vote Solar - PSC REF#: 392713](#)

[Tomahawk Power and Pulp Company's Request to Intervene - PSC REF#: 392715](#)

[CUB Request to Intervene - PSC REF#: 394186](#)

[SOUL Request to Intervene - PSC REF#: 394420](#)

[REQUEST TO INTERVENE AND NOTICE OF APPEARANCE FOR CHRIS KLOPP - PSC REF#: 394635](#)

[WIEG Request to Intervene and Notice of Appearance - PSC REF#: 394970](#)

[Baxter Request for Intervenor Status 5-EI-157 - PSC REF#: 395032](#)

[Response-Data Request-PSCW-1.5 - PSC REF#: 395553](#)

[Response-Data Request-PSCW-1.6 - PSC REF#: 395554](#)

[WPL's Response to PSC Data Request PSCW-1 - PSC REF#: 395495](#)

[WPL's Response to PSC Data Request PSCW-1 \(REDACTED COPY\) - PSC REF#: 395496](#)

[WUA Comments on Docket 5-EI-157 - PSC REF#: 393578](#)

[CONFIDENTIAL - Investigation of Parallel Generation Purchase Rates \(REDACTED COPY\) - PSC REF#: 395545](#)

Appendix A: Engineering Factors Behind Parallel Generation Avoided Costs

This appendix presents Commission staff's analysis of the engineering factors that bear consideration in determining the appropriate methods for determining avoided costs. The objective of any avoided cost analysis is to identify the potential value of a resource to the system. Avoided energy and capacity costs can be defined as the value of the incremental cost of electricity to the purchasing utility. For the reasons discussed more fully in the following sections, in determining a methodology for calculating avoided cost, consideration should be given to the following:

- The use of the market locational marginal pricing (LMP) from Midcontinent Independent System Operator, Inc. (MISO) is a good proxy for the short-term energy price.
- For longer-term analysis of LMPs, a production cost modelling approach would provide the most precise values.
- The appropriate value of the cost of avoided capacity would be most precisely determined in a generation expansion model.
- The auction clearing price (ACP) in MISO's planning resource auction for the value of capacity likely underestimates the true value of avoided capacity.

1.1 Estimation of avoided costs of electricity

1.1.1 Avoided energy cost

For determination of the avoided energy cost, MISO's LMP provides an economic signal that fully reflects both system and market operations at any specific time. LMP can be defined as the cost of providing the next megawatt (MW) of electrical energy at a specific location on the grid and factors in costs associated with energy generation, transmission congestion, and marginal line loss:

- **Energy Generation Cost:** The cost of energy generation depends on the generator type and fuel prices which fluctuate. Generators provide their operational details to MISO and offer their energy output in the MISO Day ahead and Real time markets. MISO then performs a security constrained economic dispatch where it picks the most-economic generation available at any given time to meet the load reliably.
- **Congestion Cost:** During high load demand periods, power flow is constrained due to the physical capabilities of transmission equipment to carry current while operating safely. During such congestion period the cost of energy might be higher at nodes where generation has to flow through such high traffic areas or MISO may have to dispatch a higher cost generator to the load.
- **Transmission Losses:** Some energy that is produced by the generators is lost as it is carried over by the transmission line as heat energy. The amount of transmission losses varies by the current being carried by the transmission

element and the ambient weather conditions. LMPs account for these losses to provide accurate energy price data to market participants.

The reliance on MISO's energy market for determination of avoided energy costs allows the use of location-specific avoided energy values. These values could be at the location of the load that is being offset by a generation source, or at the utility's node within its zone. LMP values are updated as the generation is dispatched in the MISO market and reflect optimal transmission system operation at any given time. Tying avoided cost of energy to the MISO energy market ensures that any changes to the market mechanisms or resource valuations are reflected in the avoided energy cost as well. LMPs can help new generation and load to locate in areas that are beneficial to them, they also inform the need for constructing new transmission facilities to relieve areas of high congestion. It is important to note that LMPs do not reflect capacity costs.

Most utilities in Wisconsin use historical LMPs to determine the avoided energy costs. Historical LMP trends can inform energy cost estimation for the short term, but may not capture the uncertainty in assumptions about the future for a longer-term energy contract. Production cost models can be used to realistically approximate the operations of MISO energy market and provide projected LMP values for current and future years. Such modeling analysis can account for key market drivers, including fuel and emission allowance prices, loads, demand-side management, generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses. Studying historical LMPs as well as analyzing current and future LMPs under various futures and scenarios can both inform a determination of the value and risks associated with long term energy contracts. For an energy contract that would last for a year or less however, an analysis using the business as usual scenario should be sufficient to provide reasonable projected LMP values.

The LMP values derived from production cost models, either under just one scenario or multiple scenarios, needs to be aggregated to estimate avoided energy costs. One of the methods to do so would be taking an annual average or around the clock price of the LMPs at the utility node or load reduction site. Such annual average, however, would not necessarily reflect differences between various generation technologies. For example, around the clock energy prices would not reflect solar generation's ability to offset peak energy demand that is usually cleared at a higher value than off-peak energy.¹

Production cost models can also be used to estimate the difference in system operation costs with and without the specific customer-owned generation system (COGS) to estimate the avoided energy benefits provided by that system. This approach might be most justified for analyzing large-scale and long-term COGS operations, and may identify that large-scale deployment can lead to decreasing LMP values.

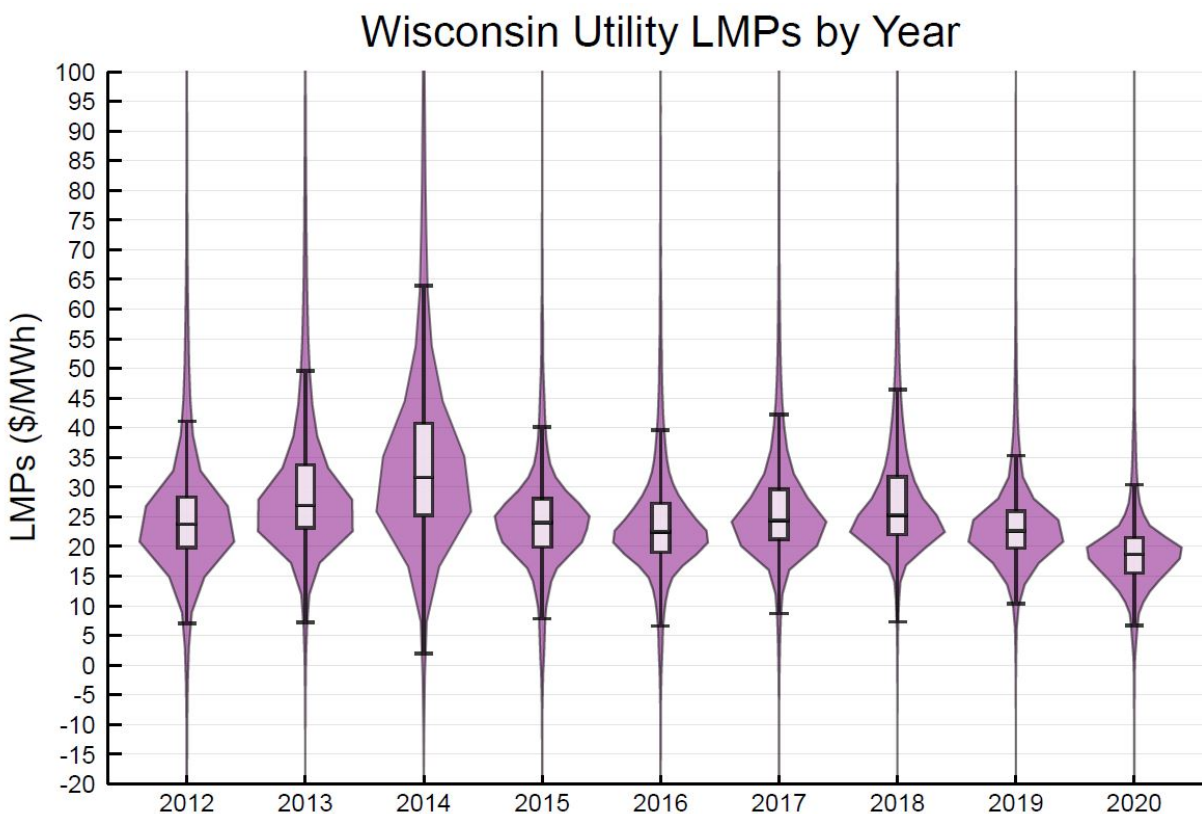
From an engineering perspective, the principles of estimating avoided energy cost can be consistent for all utilities even if the details of application of those differ between entities. Using

¹ Report to Maryland Public Service Commission: Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland. Daymark Energy Advisors, RLC Engineering, ESS Group. Nov. 2018, pp. 15-17. https://webapp.psc.state.md.us/newIntranet/AdminDocket/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/Adm inDocket/PublicConferences/PC44/145/MDVoSReportFinal11-2-2018.pdf.

production cost models for analysis of avoided cost of energy can provide transparency, consistency, and predictability required for evaluating COGS, as well as utility projects on a level playing field. The methodology for aggregating peak, off-peak, and around the clock energy prices and their use to estimate avoided cost of energy should be transparent to fully understand these costs. Such modeling effort can be time and resource intensive as it requires trained staff to set up and perform modeling analysis, equipment and software setup, and each modeling run could be 24–48 hours long or more. For smaller-sized generation, this effort might not be worth the benefit derived in terms of accuracy in results received from such modeling analysis. The accuracy of the results is also highly dependent on the accuracy and quality of available input assumptions. It might be challenging to compare various utilities' models if they are using different sources to inform their input assumptions.

LMPs in the MISO region are generally trending downwards, in part due to increased operation efficiency of MISO and the market participants, as well as increased amount of renewables on the system which are price takers. The figure below shows statewide averages for each year from 2012 to 2020; 2014 and 2020 data are likely influenced by the polar vortex and COVID-19 pandemic, respectively. 2020 data are through September 2020. See the Appendix for individual utility graphics for LMP prices for the period 2012 to 2020. These charts were derived from the MISO real-time LMP market data.

Figure 1 Distribution of MISO LMP data from 2012 to 2020



1.1.2 Avoided capacity cost

In the MISO region and in the state of Wisconsin, load serving entities (LSE) carry the obligation to meet their projected load demand and an additional planning reserve margin (PRM) determined by MISO every year. MISO determines this reserve margin requirement based on its loss of load expectation (LOLE) study, which ensures that LOLE is one day in ten years, or 0.1 day per year. A few major factors considered during the PRM analysis are: generator forced outage rates of capacity resources, generator planned outages, expected performance of load modifying resources (LMR) and energy efficiency (EE) resources, load forecast uncertainty, and the transmission system's import and export capability with external systems.²

The LOLE analysis performed by MISO uses the LSE's peak demand projections to estimate the PRM or planning reserve margin requirement (PRMR) for the LSE. The capacity resources are credited at their unforced capacity (UCAP), hence the accreditation of capacity for various types of capacity resources is critical to estimate the value of avoided capacity. These capacity resources are accredited on performance based data submitted by the asset owner (including results from Generation Verification Tested Capacity (GVTC) testing and capability to be deliverable to load within MISO's region). Behind the meter generation resources (BTMG), demand response resources (DR), and EE resources follow MISO's registration procedures to be eligible to supply capacity in the MISO region. The accredited capacity for intermittent resources is determined based on historical performance, availability, and type and volume of interconnection service. These accredited capacities or UCAP for the resources can be used by the utility towards meeting the utilities' PRMR. These resources are also held to certain performance obligations and penalized if they fail to perform as stated. Utilities can meet their PRMR for the planning year at MISO by self-scheduling resources, filing a fixed resource adequacy plan (FRAP), participating in the planning resource auction (PRA) or paying the capacity deficiency charge, which is 2.748 times the Cost of New Entry (CONE) for the zone in which the utility exists.³

The capacity requirements for an LSE can be relieved by the COGS by either providing resources that the LSE can use to meet their PRMR or by reducing the peak demand for the LSE. If the COGS does not perform either of these functions, then it does not offset the LSE's capacity requirement and does not provide capacity value for that particular entity. The federal Public Utility Regulatory Policies Act of 1978 (PURPA) establishes that the purchasing utility cannot be required to pay more for power purchased from a qualifying facility than it would otherwise pay to generate the power itself or to purchase power from a third party.

1.1.2.1 Cost of New Entry

MISO and the Independent Market Monitor (IMM) together estimate the value of CONE every year for each zone in the MISO region. For this calculation they assume the generation unit to be an advanced combustion turbine (ACT). Because ACTs provide a very high ICAP to UCAP conversion rate (96 percent or higher), they can be constructed in a two- to three-year time frame, and typically serve a peaker role with energy output limited to less than 10 percent

² Planning year 2020-2021, MISO's LOLE study report.
<https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf>.

³ MISO's Resource Adequacy Business Practice Manual, BPM-011-r23, Effective Date: March-31-2020.

capacity factor, they are frequently identified as the most likely unit to be used to address capacity-specific needs. MISO and IMM use data supplied by the Energy Information Administration and Bureau of Economic analysis for this estimation. The assumptions used by MISO and the IMM for this analysis are comparable to those used by other RTOs in the development of CONE estimates.

MISO uses CONE during settlements of its PRA. The capacity prices in MISO during PRA are capped at CONE in case of inadequate supply to meet demand in each local resource zone (LRZ). The PRA, as explained earlier, is a residual capacity market, and the use of CONE as an indicator of new generation being required within the zone is reasonable. CONE however, by itself, is not an accurate indicator of the value of avoided capacity for every utility. The marginal unit for various utilities under different futures and scenarios might be different based on their energy and capacity positions and other geographical or planning limitations. Renewables like solar generation in many cases can compete with advanced combustion turbine technology to provide capacity and shorter timelines from planning to operation.⁴

1.1.2.2 Planning Resource Auction

All the load-balancing authorities in the Wisconsin MISO region meet their PRMR by filing their FRAP and self-scheduling. The FRAP identifies resources that an LSE has ownership or contractual rights that will be relied upon to meet the LSE's PRMR while also conforming to the local clearing requirement (LCR) in each zone. LCR is the amount of capacity that the LSE needs to procure from within its zone to meet its demand. The utilities submit their FRAPs to MISO by March prior to each planning year, and have until the PRA offer window opens to resolve any issues identified by MISO.

MISO's capacity market consists of an annual PRA process which is conducted in the beginning of April every year, two months before the beginning of the associated planning year. The PRA is a voluntary residual capacity market where resources that were not used in FRAP can be offered in during the auction window period. MISO clears these offers based on the needs of the LRZ and not the size of any resource. Once the offer window closes, the engineering analysis to clear capacity while respecting capacity import and export limits and sub-regional import and export constraints is performed to ensure feasibility of the optimal solution. The results of the PRA include MISO system-wide and each LRZ's: PRMR, FRAP, self-scheduled resources, Import/Export limits and amount, ACP, deficient amount, and total offer cleared volume for the system.

A few things to consider while assessing the use of PRA ACP as an indicator for avoided capacity costs:

- PRA is a voluntary residual capacity market, and it is possible for LSEs to meet their PRMR without participating in this market.

⁴ Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020, EIA. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

- MISO's capacity market does not have a forward capacity requirement, so the ACP is applicable only to the upcoming planning year.
- ACP excludes some charges and benefits seen by the LSE, such as zonal deliverability charges and benefits and zonal deliverability charge hedges.
- As shown in Figure 2, Clearing results show a history of generally low prices, with high year-to-year price volatility, and occasionally substantial price differences across zones.⁵

Figure 2 MISO PRA Clearing Results since 2014-15

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2014-2015	\$3.29	\$16.75						\$16.44		N/A	N/A
2015-2016		\$3.48		\$150.00		\$3.48		\$3.29		N/A	N/A
2016-2017	\$19.72	\$72.00						\$2.99			N/A
2017-2018		\$1.50									N/A
2018-2019	\$1.00	\$10.00									N/A
2019-2020		\$2.99					\$24.30		\$2.99		
2020-2021		\$5.00					\$257.53	\$4.75	\$6.88	\$4.75	\$4.89-\$5.00

NOTE: AUCTION PRICES IN \$/MW-DAY. "ERZS" ARE EXTERNAL RESOURCE ZONES.
SOURCE: MISO, "2020/2021 PLANNING RESOURCE AUCTION (PRA) RESULTS," APRIL 14, 2020.

Brattle.com

- While PRA enforces the resource adequacy requirements, ACPs are valid for only one year, and volatility from year to year can affect its value as a price signal for making long-term investment decisions such as generation additions or retirements.
- PRA in the MISO region uses a single requirement vertical demand curve based on the capacity requirement for operating reliably. The demand for capacity is a function of the reliability it provides and diminishes as the quantity of capacity rises. But when a single requirement vertical slope is used, the market tends to clear at close to zero price if any additional capacity over the capacity requirements is available. However, if the available capacity is short by even a small amount, the clearing price is much higher, and could match CONE. The lack of gradual price increase or decrease based on the amount of excess resources or shortfall of resources leads to high deficiency prices as soon as the market is short, and very low prices if the market is long.
- PRA results provide ACP for the entire zone and not by utility. For example, if the PRA for a specific zone clears at CONE but a few of the utilities in the zone

⁵ Evaluating MISO's Planning Resource Auction, August 2020, [https://cdn.misoenergy.org/20200805%20RASC%20Item%2003c%20Evaluating%20MISOs%20PRA%20Brattle%20Presentation%20\(RASC011\)463582.pdf](https://cdn.misoenergy.org/20200805%20RASC%20Item%2003c%20Evaluating%20MISOs%20PRA%20Brattle%20Presentation%20(RASC011)463582.pdf).

did meet their LCR, the net ACP for those utilities will not be CONE. However, they could be estimated based on ACP.

1.1.2.3 Capacity expansion planning models

Conventional capacity expansion planning models can optimize the generation portfolio for any entity while considering energy and capacity demand, reserve margins, ramping rates, must-run status of units, heat rates, and many other generator operational criteria. The objective of these models is cost minimization under the defined system constraints. The utility system costs can be analyzed with and then without the COGS to estimate the capacity value of the COGS to that particular utility. This methodology can be used to analyze short-term as well as long-term capacity costs. Short-term capacity contracts can be studied under business as usual future. Any impacts of utilities internal policy goals or state regulators policies can be studied using these models. Long-term capacity holds a higher value than short-term capacity and the avoided costs for longer-term capacity contracts can also be studied using this methodology. Long-term capacity analysis requires studying the COGS contract under various possible futures and sensitivities, then aggregating the revenue requirement impact of including the COGS in each of those to derive the avoided value of capacity for a specific utility.

Some other advantages of this methodology include:

- Ability to analyze the system under key variable changes like price of fuel, policy requirements, emission control requirements, changes to the generation fleet, etc.
- Many capacity expansion models allow the energy prices to be included in the analysis to realize the value of both avoided energy and capacity costs for a particular COGS contract. Some capacity expansion models are capable of analyzing the system under a limited number of transmission constraints as well.
- It does not define any specific technology for the marginal unit for every utility and selects the most optimal unit to meet the utilities needs under various futures or scenarios from a pool of pre-defined alternatives. Thus, this methodology provides flexibility as the resource mix and fleet changes for the utility. It can also be used to analyze multiple generation bids at the same time, which can be beneficial to the utility as well as the bidding entity to inform their investment decisions.
- Wisconsin utilities have long used generation expansion modeling for planning new generation, purchased power agreement contracts, or retirements, and are aware of this approach to analyses the value of their resources.
- The avoided capacity cost derived using this method is specific to the utility and the COGS under the defined terms of the contract.

While modeling the COGS for such analysis, it is important to represent the reduction in PRMR for the utility or reduction in demand provided by this resource appropriately. Avoided capacity costs should be defined on the basis of the system capacity need deferment and not the capacity value of the resource being considered. Most utility resources provide the benefit of

utility-controlled operations required to satisfy the MISO grid operating schedules. If the COGS under consideration do not provide the same performance standards, amount of controllability, and flexibility as the utility resource, then those factors need to be accounted for while estimating avoided capacity costs.

The input assumptions for these capacity expansion models, like any other modeling approach, can largely affect the value of the avoided costs and need to be made transparent along with the method used to aggregate the system revenue requirements differentials to evaluate avoided capacity cost. Similar to the production cost modeling, capacity expansion modeling effort can be time- and resource-intensive, as it requires trained staff to set up and perform modeling analysis, equipment and software setup, and the run time for such models is usually shorter as compared to production cost models. For smaller-sized generation, this effort might not be worth the benefit derived in terms of accuracy in results received from such modeling analysis. The accuracy of the results is also highly dependent on the accuracy and quality of available input assumptions. It might be challenging to compare various utilities models if they are using different sources to inform their input assumptions.

1.1.3 Other avoided cost components

A few other components of avoided cost of electricity are ancillary services and transmission and distribution components. Along with these, policy goals, if considered, can affect the value of avoided costs seen by the utility. These costs when included as components in determining avoided costs need to be specified explicitly and the process of estimating their values be made transparent.

1.1.4 Effects of changes at MISO on Avoided Cost Estimation

Under MISO's ongoing Resource Availability and Need (RAN) initiatives, multiple proposals to address the resource gap between planning and operations seen in MISO are being analyzed. If implemented, these initiatives could impact the assessment of the avoided costs for resources in Wisconsin.

- Resource Accreditation (RASC010⁶) is targeted at addressing the gaps in resource accreditation to incentivize resources to be available during times of need. This will likely affect the values for non-intermittent capacity resources due to change in how outages are accounted for. It will also likely affect the accreditation values for intermittent as well as LMR resources. The PRM values for Planning Year 2021/21 increased by 0.5 percent, and the main driver for that change was the outage modeling of capacity resources.⁷ For the utilities that use PRA ACP to inform their avoided capacity costs, these accreditation changes will impact the values currently used.

⁶ Resource Availability and Need (RAN) - Resource Accreditation (RASC010)
<https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran-seasonal-resource-adequacy/>.

⁷ 2021/22 PY Planning Reserve Margin and Local Reliability Requirement- Draft Results.
<https://cdn.misoenergy.org/20200908%20LOLEWG%20Item%2003%202021-22%20PY%20PRM%20LRR%20Results472186.pdf>.

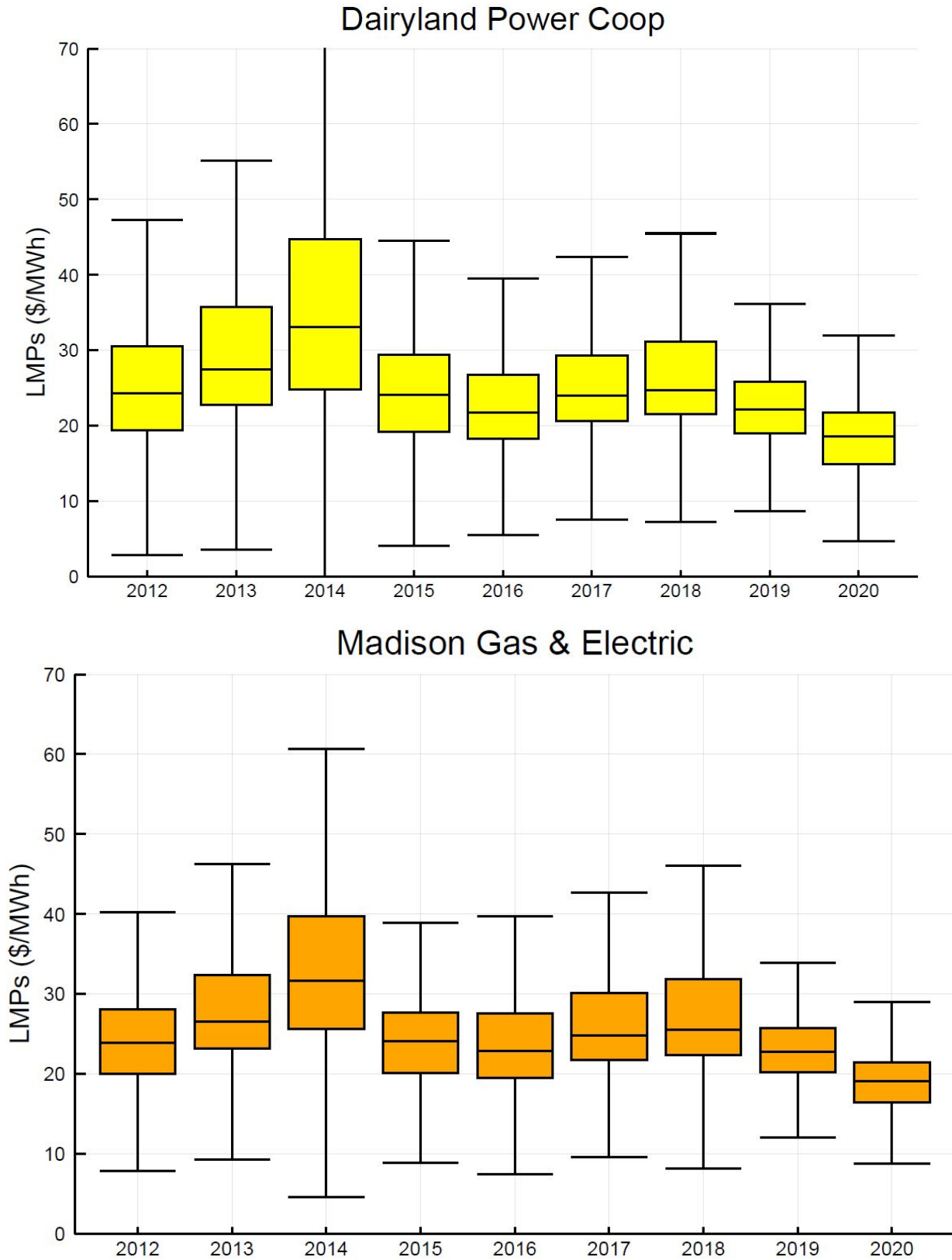
- Resource Adequacy Construct (RASC011⁸) is considering a seasonal or more granular construct for PRA to achieve better representation of resource capabilities and more accurate price signal. It is likely that MISO will move to sub annual PRA and PRMR requirements. Since many utilities use PRA ACP to estimate avoided capacity costs, this will have an impact on how those will be analyzed.⁹ These changes could improve the accuracy of PRA ACP in measuring short-term capacity values, although they do not address all of the considerations mentioned above.
- Reliability Requirements and Metrics (RASC012¹⁰) is targeted to address the reliability metric used to estimate the resource adequacy requirements to operate MISO system reliably. The LOLE metric does not effectively capture the effects of an increasingly diverse portfolio to meet the system's needs, hence, MISO is considering other metrics for such analysis. For the utilities that use PRA ACP to inform their avoided capacity costs, these reliability metric changes will have an impact on the MISO PRA construct as well as the PRA ACP.

⁸ Resource Availability and Need (RAN) - Resource Adequacy Construct (RASC011)
<https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran---resource-adequacy-construct/>.

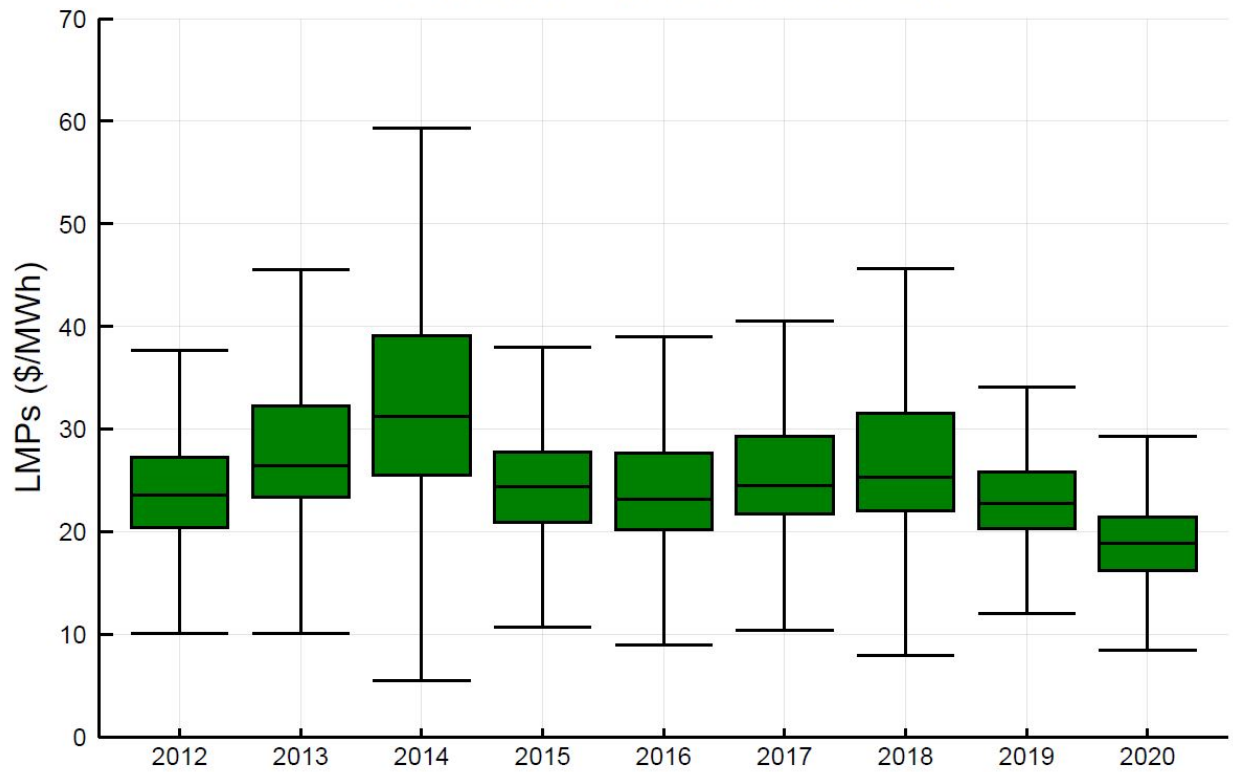
⁹ RAN Reliability Requirements and Sub-annual Construct.
[https://cdn.misoenergy.org/20200909%20RASC%20Item%2003a%20RAN%20Reliability%20Requirements%20and%20Sub-Annual%20Construct%20Presentation%20\(RASC010,011,012\)472525.pdf](https://cdn.misoenergy.org/20200909%20RASC%20Item%2003a%20RAN%20Reliability%20Requirements%20and%20Sub-Annual%20Construct%20Presentation%20(RASC010,011,012)472525.pdf).

¹⁰ Resource Availability and Need (RAN) - Reliability Requirements and Metrics (RASC012)
<https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran---reliability-requirements--metrics/>.

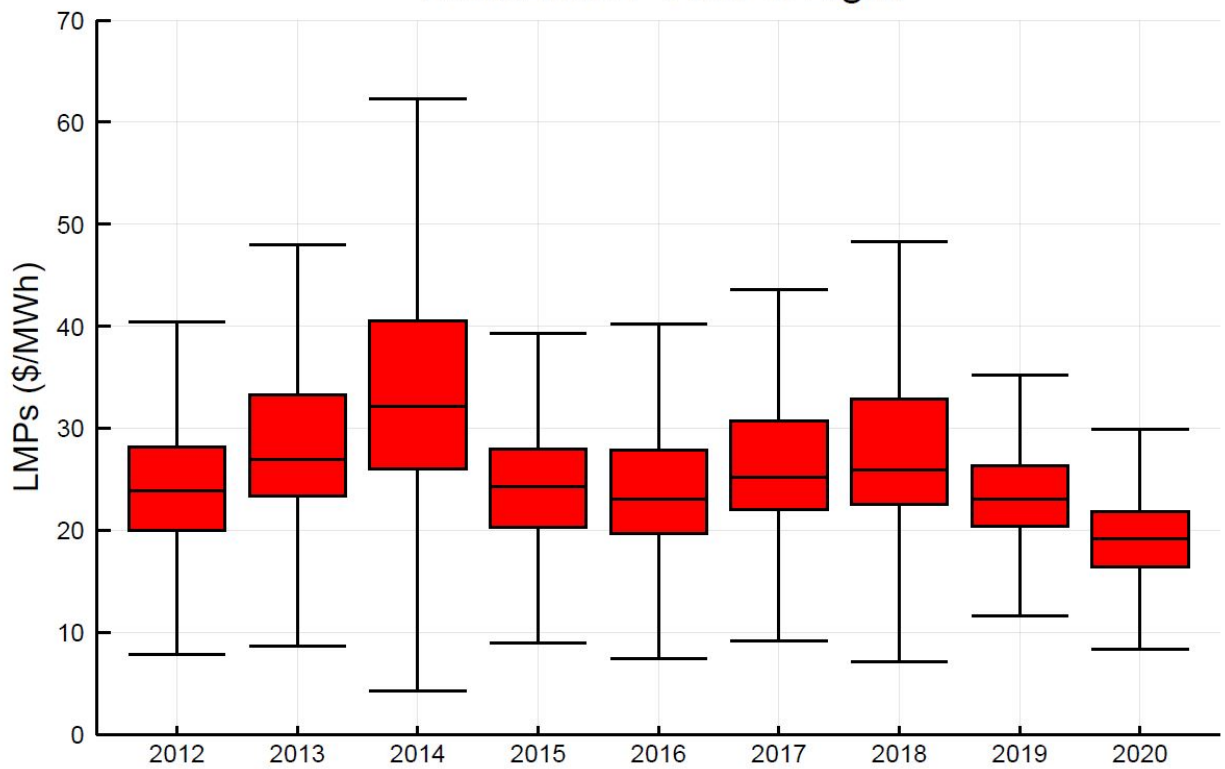
Appendix: Wisconsin LMPs by Year and Utility

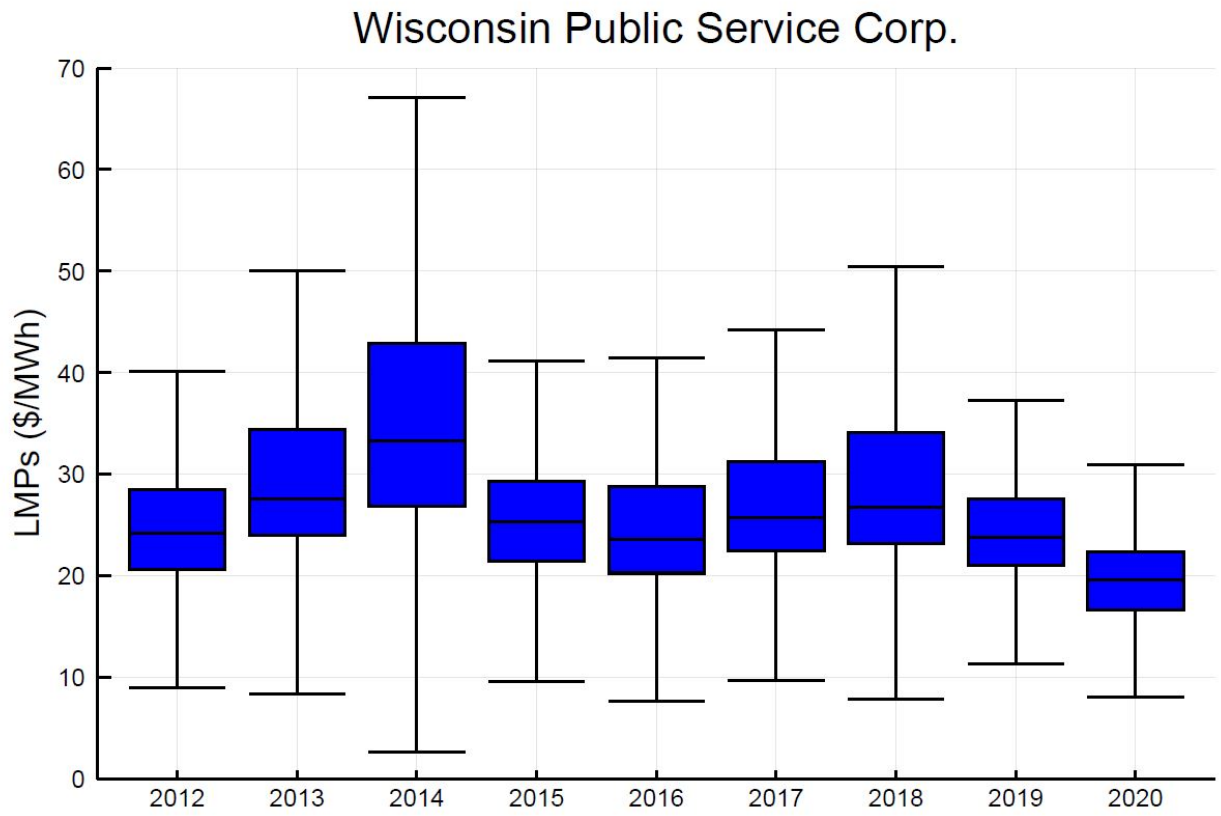


Wisconsin Electric Power Co.



Wisconsin Power & Light





DL: 01775387

Appendix B: Economic Aspects of Parallel Generation Purchase Rates

Appendix B is organized as follows:

- 1. Executive summary**
- 2. Background**
 - a. Economic concepts
 - b. The concept and applicability of avoided cost
 - c. PURPA and its provisions
 - d. Alternative avoided cost determination methodologies available
 - e. Review of comments submitted and filed in this docket.
- 3. Analysis**
 - a. Implications of the relevant economic concepts
 - b. Functional aspects of avoided cost
 - c. The specificity required to apply the economic concept
 - d. Practical challenges faced in applying the economic concept
 - e. Introducing compulsion to the application of the concept
 - f. Analysis of the alternative avoided cost methodologies available
 - g. Engineering, environmental, and other technical considerations overlapping with the economic ones
 - h. Review of comments submitted and filed in this docket
- 4. Conclusions**
 - a. Applicability of any one single avoided cost methodology
 - b. Applicability of MISO's capacity auction
 - c. Applicability of MISO's CONE calculation

1. Executive Summary

From an economic perspective, parallel generation purchase rates are intended to reflect the avoided cost associated with the incumbent public utility accepting the capacity, energy, ancillary and/or other services to be provided by the proposed parallel generation. Parallel generation includes both generation facilities that qualify as qualified facilities (QF) under the Public Utilities Regulatory Policies Act 1978 (PURPA) and those that do not.

Avoided costs, in turn, are the incremental savings associated with not having to produce additional units of electrical capacity and/or energy while meeting electrical service demand requirements.

In principle, using the marginal cost avoided creates an incentive for both parties (the one producing and the one consuming electrical capacity and/or energy and/or ancillary services) to agree on a mutually fair and just price. Material challenges, however, emerge from various facts and factors that can make it challenging to apply this principle in practice.

In addition, there are several challenges to replacing an effective market with an effective substitute. Prominent among them:

- Asymmetries between the interested parties;
- Differences among various parallel generation installations, including location and scale;
- Ongoing changes in technologies;
- Ongoing changes in the economic characteristics of the various technologies;
- Ongoing changes in fiscal and environmental policies and rules; and
- Regulatory policies related to generation operation and ownership.

Several alternative approaches have evolved to determine avoided cost rates. A number of them have been developed in response to PURPA. Six of the best-established methodologies are reviewed in this memorandum: competitive bidding, proxy unit, combustion-turbine peaking unit, differential revenue requirement, integrated resource planning, and market-based pricing.

Several technical, mostly engineering and environmental, considerations overlap with the economic ones in considering this matter, and can also be taken into account in assessing the establishment of parallel generation purchase rates.

Finally, this analysis also reviewed the public comments that were filed in this docket.

The economic analysis in this paper identifies the following key considerations:

- No single avoided cost methodology applies properly to all situations.
- The clearing prices from the Midcontinent Independent System Operator, Inc. (MISO) capacity auction mechanism may not reflect the applicable avoided cost in a number of situations.

- The Cost of New Entry (CONE) calculation used and applied by MISO also may not reflect the avoided cost for capacity in a number of situations.
- Because the full range of direct market pricing signals are not readily available to the analyst, energy and electric service prices must be estimated through available proxy data:
 - MISO's locational marginal price (LMP) is an adequate market energy price signal for energy cost, but is currently only available for very near-term time horizons (same-day and next-day). Other proxies for long-term price signals are available, such as energy futures contract pricing and financial transmission rights hedging (FTR).
- Given the complications above, and the varying contexts in which parallel generation may be deployed (location, timing, scale, available technology, etc.), it could be reasonable to assess whether regulatory adjustments can help mimic efficient market conditions in order to generate useful pricing signals and allow the interested parties to negotiate mutually acceptable terms and conditions.

2. Findings

a. Economic concepts

From an economic perspective, parallel generation purchase rates are intended to reflect the avoided cost associated with the incumbent public utility accepting the capacity, energy, ancillary and/or other services to be provided by the proposed parallel generation.

- i. A number of practical challenges can emerge in seeking to establish the appropriate purchase rate for any specific case,
- ii. These practical challenges can relate to the establishment of current avoided costs, as well as the fact that the avoided cost in any one particular case can change over time.
- iii. The valuation required to determine an appropriate avoided cost requires the identification and quantification of all relevant aspects of the proposed parallel generation, expressed as expected values. These include the engineering, environmental and other technical factors, both positive and negative.
- iv. A market-clearing price would be an efficient and accurate way of determining the avoided cost in any particular case. Well-informed parties would be able to establish a viable range of parallel generation purchase prices that would reflect the avoided cost, with neither party feeling compelled to accept an uneconomic purchase price. In light of the practical challenges involved, regulators and participating parties can consider available alternative methods to identify avoided cost values.

b. The concept and applicability of avoided cost

- i. Avoided costs are the incremental savings associated with not having to produce additional units of electrical capacity and/or energy while meeting electrical service demand requirements by relying on parallel generation.
- ii. Efficiency gains are realized as long as the marginal benefit of a particular resource option exceeds its marginal cost. The marginal or incremental cost is used to refer to the unit cost of production for a given resource technology that results in a specified incremental amount of electrical capacity and/or energy and/or ancillary service.

c. PURPA and its provisions

This discussion is limited only to the economic and financial consequences of PURPA, and does not intend to be an exhaustive description or discussion of this statute or of its regulatory framework.

Three consequences of the enactment of PURPA are worth highlighting for the purposes of this discussion:

- i. The statute encouraged alternative energy development that was intended to complement the existing generation fleet;
- ii. The statute created the QF status for generation facilities that met certain criteria; and
- iii. The statute intended to maintain ratepayer neutrality.

The statute requires public utilities to purchase power from QFs, and requires that purchased power from QFs must be set at avoided cost based rates, which aligns with the economic concepts set out above.

Among other things, Federal Energy Regulatory Commission's (FERC) PURPA rules:

- Defined "avoided cost" as follows:

... the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source ...

(18 CFR § 292.1010(b)(b).)

- Require companies to make avoided cost data publicly available; and
- Must meet a just and reasonable, non-discriminatory standard.

The Energy Policy Act of 2005 (EPACT 2005) and FERC's recent Order 872 have relaxed that requirement for certain QFs with access to competitive markets.

d. Alternative avoided cost determination methodologies available

This discussion is limited only to the economic and financial aspects of alternative avoided cost methodologies. It does so by examining the generic methodologies that are most commonly identified for establishing avoided cost values; it does not intend to be an exhaustive description or discussion of the evolution of alternative methodologies that have emerged over time in various jurisdictions.

The six most commonly identified alternatives to determine avoided cost rates in response to PURPA's requirements are:

- 1) The competitive bidding methodology;
- 2) The proxy unit methodology;
- 3) The peaker unit methodology;
- 4) The differential revenue requirement methodology;
- 5) The integrated resource plan (IRP)-based methodology; and
- 6) The market-based methodology.

Methodologies	Description
Competitive bidding methodology	Allows the state to utilize open bidding processes to establish the avoided cost. The intent is to solicit fair, impartial and competitive bids.
Proxy unit methodology	Premised on the public utility avoiding the construction and operation of an equivalent generating unit being considered by estimating the terms upon which it would be willing to agree to acquire a parallel generation unit's capacity, energy and/or services.
Peaker unit methodology	Broadly accepted when the natural gas-fired combustion turbine (CT) has been deemed to be the marginal generating unit for most utility systems.
Differential revenue requirement methodology	Estimates the difference in revenue requirements for the public utility in operating <i>with</i> and <i>without</i> the parallel generating unit's contribution to its generation fleet.
IRP-based methodology	The IRP-based approach can use any of the preceding four methodologies and applies it according to a state-established IRP process.
Market-based pricing methodology	QFs with access to non-discriminatory competitive markets receive capacity and/or energy payments at market rates.

i. The competitive bidding methodology

Allows the state to utilize open bidding processes to establish the avoided cost. The intent is to solicit fair, impartial and competitive bids.

- a. A number of alternative procedures have evolved overtime, among them:
 - Both single-source and multiple-source processes; and
 - Request for proposal (RFP) processes.
- b. The process can set out the problem to be solved, as opposed to the desired solution, as a way to encourage creative responses.
- c. The competitive bidding can be technology-agnostic.
- d. The competitive bidding process can follow different formats, such as descending clock auctions, sealed-bid RFPs, first-price auctions and market-clearing price auctions.
- e. Regulators can evaluate the results on either an *ex ante* or an *ex post facto* basis.
- f. The process can use the services of an independent evaluator to determine the winning bidder.
- g. In some cases, the process is designed to invite bidders to consider and offer a range of ownership structure alternatives.
- h. In some cases, third party advisors are employed to help establish solicitation processes that are adequately clear regarding:
 - the needs to be met;
 - the criteria for awarding the contract being equally complete and clear; and
 - the necessary information being appropriately provided to ensure a level playing field among competitors.

Third parties may also be employed to provide independent evaluation of submitted bids.

ii. The proxy unit methodology

Premised on the public utility avoiding the construction and operation of an equivalent generating unit being considered by estimating the terms upon which it would be willing to agree to acquire a parallel generation unit's capacity, energy and/or services.

- a. To implement this method, a purchasing utility can prepare engineering, design, procurement and construction estimates for the proxy unit.
- b. The public utility then projects its operating and maintenance costs for that same pre-determined period of time.
 - These estimates are subject to review and challenge.
 - The fixed costs of this hypothetical proxy unit sets the avoided capacity costs.
 - The variable costs of this hypothetical proxy unit sets the avoided energy costs.

iii. The peaker unit methodology

Broadly accepted when the natural gas-fired CT has been deemed to be the marginal generating unit for most utility systems.

- a. The methodology is premised on the assumption that a QF or other parallel generation unit would allow the public utility to avoid paying for the construction and operation of a CT marginal unit.
- b. The gas-fired CT is deemed to be the marginal generating unit due to the following characteristics:
 - The speed with which the unit can be designed, sited and brought into operation, which is more comparable to the typical QF unit.
 - Its marginally higher operating cost, when compared to a baseload generating plant, which is mitigated by peaker plants being designed to be operated infrequently for relatively short periods of peak demand when the value of the output exceeds its higher marginal operating cost; and
 - The fast-ramping ability when compared to conventional baseload plants, which reflects the fact that CT units are not designed for extended periods of operation.
- c. The capacity payments are based on the fixed costs of the public utility's least-cost peaker unit.
- d. The energy payments are forecast for that peaker unit over the life of the proposed contract with the QF or other parallel generation unit.

iv. The differential revenue requirement methodology

Estimates the difference in revenue requirements for the public utility in operating with and without the parallel generating unit's contribution to its generation fleet.

- a. This methodology approaches the estimation of avoided cost by estimating the difference in revenue requirements for the public utility in operating **with** and **without** the QF's or the non-QF parallel generating unit's contribution to its generation fleet.
- b. This methodology typically requires a full revenue requirement analysis associated with a typical contested rate case filing, and is subject to the same degree of review and challenge.

v. The IRP-based methodology

The IRP-based approach can use any of the preceding four methodologies and applies it according to the state-required IRP.

- a. The IRP-based approach can use any of the preceding four methodologies and applies it according to the state-required IRP.
 - **Step 1:** Rely on the IRP to predict future needs and costs that will be avoided by QF generation.
 - **Step 2:** Based on the IRP, apply the competitive bidding, proxy unit, peaker unit, differential revenue requirement or other avoided cost calculation methodology.

vi. The market-based methodology

QFs with access to non-discriminatory competitive markets receive capacity and/or energy payments at market rates.

- a. QFs receive capacity and/or energy payments at market rates.
- b. The efficacy of this method is dependent on the accuracy of those market rates in reflecting avoided costs. Considerations regarding the accuracy of MISO market rates applicable to Wisconsin are analyzed below.

3. Analysis

a. Implications of the relevant economic concepts

The relevant economic concepts identified in Section 2(a) above raise a range of considerations for this investigation:

- i. The avoided cost of any particular form of parallel generation will be a function of several factors, among them:
 - Whether there is demand for the particular service offered to the incumbent public utility, which may be long, or anticipates being long, in those resources required to meet the electrical service needs of those customers it is required to serve;
 - The demand for the particular potential services on offer;
 - The ability of any potential supplier to offer the particular service required by the incumbent public utility;
 - The technology available;
 - The engineering, environmental and other technical implications, identified and quantified;
 - The proposed siting of the parallel generation resource, with its access to any required fuel, storage and/or delivery facilities; and
 - The timing of the contemplated parallel generation being offered.
- ii. The significance and availability of accurate and applicable pricing signals to guide the discussions and decisions required to reach a fair and reasonable set of terms and conditions.
- iii. The value of transparency regarding the needs and the decision criteria that will be applied in evaluating alternatives.

The significance of symmetry of information and of negotiating leverage among the interested parties.

- iv. The recognition that the supply and demand functions of the various services (capacity, energy and ancillary services) are different, are subject to different drivers and may therefore not lend themselves to a single co-optimal solution.
- v. The recognition that the variety of existing and emerging energy generation and storage technologies, with the different cost and operating characteristics, imply that a single approach or method may not serve the range of situations that arise between public utilities and a variety of potential parallel generators.
- vi. The potential financial risks that the proposed parallel generation might create for the incumbent public utility, in terms of its ability to meet its obligations to serve safely and reliably, to the degree that those obligations cannot be transferred and assumed by the parallel generator as part of a commercial transaction freely entered into by both parties.

b. Functional aspects of avoided cost

In principle, the marginal cost avoided creates an incentive for both the party producing electrical capacity and/or energy and the party consuming that electrical service.

The marginal avoided cost becomes the market-clearing price for that incremental electrical capacity and/or energy. For that market-clearing price to emerge naturally, several factors are required:

- a. Willing parties to consider entering into a transaction;
- b. Well-informed parties which can evaluate a potential transaction;
- c. Symmetrical levels of market knowledge among the potential parties to a transaction;
- d. A potential pricing range that allows for the counterparties' interests to be served:
 - i. A bid low enough to more than match the cost of self-building the resource; and
 - ii. An offer high enough to more than cover the required costs and risks to be absorbed;
- e. A level playing field, meaning the absence of market distortions; and
- f. Unbiased and transparent regulatory treatment and evaluation, inclusive of reliability compliance obligations.

c. The specificity required to apply the economic concept

To establish a reasonable market-clearing price, the following conditions must be taken into account:

- a. The financial needs of the various potential counterparties being met by the proposed transaction;
- b. The technical requirements of the various potential parties;
- c. The timing requirements of all parties involved;
- d. The technologies available to all parties at that particular time; and
- e. The procurement process allowed to the potential counterparties.

In addition, the market-clearing price determination is affected by the specific current and anticipated environmental conditions:

- a. Financial and tax incentives applicable to the proposed transaction;
- b. Statutory and regulatory constraints and precedents applicable to the potential counterparties and the proposed transaction; and
- c. Funding alternatives available to the potential counterparties and investor risk tolerances applicable to the proposed transaction at the time.

d. Practical challenges in applying the economic concept

The previously discussed concepts face several practical challenges when regulated public utilities are involved in establishing a market-clearing price that accurately reflects the avoided costs associated with a parallel generation transaction.

The monopsony effect influences the ability to establish symmetrical levels of market influence among the potential parties to a transaction. A monopsony market has a single buyer, and is the buying-side equivalent of monopoly market that includes a single seller. Most public utilities are in a monopsony position regarding the purchase of energy produced by a parallel generation system. Moreover, the cost recovery paradigm incorporated into most public utility regulation limits the potential for earning profits to that public utility's return on equity and the amount of equity invested in the regulated operating company, which in great measure is a function of the size of its rate base.

The practice of transferring the recovery of stranded asset costs to customers affects the decision-making process associated with retiring fixed assets through the transfer of some investment risk, affecting the determination of a market-clearing price driven by avoided costs.

Regulatory practices, by transferring some investment risk, can also affect the willingness of public utilities to introduce new technology without directly controlling the manner and pacing of that new technology itself, as opposed to it being controlled by an independent third party, which in turn impacts the process of developing a market-clearing price that is driven by avoided cost. A vertically integrated public utility company may also be concerned about integrating any contracted generation into the rest of its operating system while simultaneously complying with its balancing and reliability obligations. These concerns might also be further complicated by that public utility's need to co-optimize its service territory's energy market operations and planning with those arising from its wholesale energy market operations and planning at a regional level, under the responsibility of MISO.

e. Policy considerations involved in addressing practical challenges

When practical and other challenges interfere with the formation of market-clearing pricing that accurately reflect avoided costs, the challenge

becomes that of recreating price-discovery mechanisms that accurately mimic those of effective markets.

One aspect of that challenge is that of balancing competing policy objectives, among them:

- a. Providing a predictable outcome versus encouraging flexibility to be able to reflect the specific factors driving an avoided cost market-clearing price; and
- b. Offering consistent treatment versus adapting to the continuous change in technology and markets.

f. Analysis of the alternative avoided cost methodologies available

The six methodologies described in Section 2(d) above have characteristics that make them more or less appropriate in determining the avoided cost in any particular situation. The following analysis highlights their key advantages and disadvantages:

1) Competitive bidding methodology

Allows the state to utilize open bidding processes to establish the avoided cost. The intent is to solicit fair, impartial and competitive bids.

The advantages associated with this methodology include:

- Takes advantage of the experience, understanding and capabilities of the entire marketplace, not just those of the incumbent public utility.
- Explicitly addresses the incentives public utilities face to grow their rate base, and is more flexible in allowing bidders to incorporate several alternative ownership structures that might best serve all parties, while simultaneously transferring know-how to the public utility in the case of evolving technologies.
- Can help the marketplace address and answer questions of technological viability
- Regular competitive procurement over time can encourage increasingly tighter pricing and higher quality in repeat bidders.
- Promotes the avoidance of cost overruns, delays and underperformance.
- Increases transparency and confidence in the incumbent public utilities and their regulators.
- Promotes competition where reasonably possible.

The disadvantages associated with this methodology include:

- The variation in the legal framework governing different jurisdictions nationwide.
- The challenges of balancing the markets' offerings and innovations with the need for a well-defined product.
- The computational challenges in evaluating heterogeneous products and proposals.
- The methodology might be too complicated for smaller QFs and smaller parallel generation facility proposals.

2) **Proxy unit methodology**

Premised on the public utility avoiding the construction and operation of an equivalent generating unit being considered by estimating the terms upon which it would be willing to agree to acquire a parallel generation unit's capacity, energy and/or services.

The advantages associated with this methodology include:

- If done well, it follows the intention of PURPA in setting the avoided cost standard.
- This methodology also enhances the ability of the incumbent public utility to clearly and exhaustively specify the desired outcome. Any potentially adverse impacts on the incumbent public utility's generation fleet and ability to meet safety, reliability and operational standards might be more quickly identified and avoided.

The disadvantages associated with this methodology include:

- Does not directly correct the challenges posed by asymmetry of information and negotiating leverage,
- More likely to be driven by a pre-decided technical solution, with the advantages of soliciting novel alternatives consequently de-emphasized.
- May overstate costs.

3) **Peaker unit methodology**

Broadly accepted when the natural gas-fired CT is deemed to be the marginal generating unit for most utility systems.

The advantages associated with this methodology include:

- The gas-fired CT is the accepted standard marginal generation unit in public utility generation fleets.

- The time to design, site and construct the peaker plant is closer to that of most QFs, making it more closely comparable.

The disadvantages associated with this methodology include:

- The methodology relies on an assumption that a gas-fired CT unit is the best solution, or at least the solution most likely to be applied to meet capacity needs. In addition, the technological and economic characteristics are starting to change, as well as strong preferences beginning to have a marked impact on the kind of generation technology required by customers, particularly those able to introduce parallel generation that favor alternatives other than gas-fired generation and are able to shift load away from peak periods by using energy storage and other methods.
- It may not be the appropriate marginal unit for capacity and/or ancillary services.
- It may not be the appropriate benchmark for a non-peaking parallel generating unit or QF.
- It may not be an appropriate proxy for parallel generation units that are not gas-fired and/or are paired with energy storage as hybrid units.

4) Differential revenue requirement methodology

Estimates the difference in revenue requirements for the public utility in operating with and without the parallel generating unit's contribution to its generation fleet.

The advantages associated with this methodology include:

- If done as thoroughly as is done when preparing a rate case filing, with the supporting testimony of expert witnesses and the type of challenges associated with contested rate cases, it can provide a reasonable estimate of the avoided cost as a result of the rigorous preparation and sensitivity analyses undertaken in contested proceedings.
- The methodology lends itself more easily to detecting the marginal impact on customers, at least over the timeframe used for a rate case (in Wisconsin, traditionally that would be two years forward).
- The methodology would be subject to the type of review and challenge associated with a full rate case.

The disadvantages associated with this methodology include:

- It is a complex and labor-intensive methodology for all parties concerned.

- Not as transparent as other methodologies.
- The analysis is shorter-term than the typical QF contract term, or the operating lifetime of a non-QF parallel generation unit.
- This methodology assumes that the QF or proposed parallel generating unit is the marginal generating unit, which may not be the case in any one particular situation.

5) **Integrated resource plan (IRP-based) methodology**

The IRP-based approach can use any of the preceding four methodologies and applies it according to the state-required IRP.

The advantages associated with this methodology include:

- It has the advantages associated with any of the avoided cost estimation methodologies that is chosen.
- It also has the advantage of framing the analysis within the context of a formally filed IRP, which enhances transparency to the determination of the avoided cost.

The disadvantages associated with this methodology include:

- It has the disadvantages associated with any of the avoided cost estimation methodologies that is chosen.
- The absence of an IRP requirement in the Wisconsin jurisdiction.
- The resulting analysis might still be shorter-term than the typical QF contract term, or the operating lifetime of a non-QF parallel generation unit.

6) **Market-based pricing methodology**

QFs with access to non-discriminatory competitive markets receive capacity and/or energy payments at market rates.

The advantages associated with this methodology include:

- In principle, appropriate market pricing signals can help identify what the avoided costs are, provided the pricing is comparable to the products and services on offer.
- With care, pricing signals that are not strictly comparable but that can be reasonably adjusted (to reflect differences in situs, for instance) can also be helpful.

The disadvantages associated with this methodology include:

- In many cases reasonably accurate and applicable market pricing signals may not be available
- The markets may not be strictly comparable to the specific products and services being proposed.
 - MISO's energy markets are limited to next-day and same-day markets.
 - MISO's capacity auction market is conducted annually and is may not reflect the specific requirements that a parallel generation proposal might address.
- There might not be liquid markets for certain ancillary services for the terms that might be desired or might be optimal for the specific parallel generation proposal.
- The existence of markets for particular products and services may evolve and be discontinued, which poses a challenge in using this methodology for longer-dated arrangements.

g. Review of Comments Submitted and Filed in Docket 5-EI-157

- i. The comments reflect a wide range of perspectives on the matter covered by this generic docket. That in itself suggests that there is no single universally acceptable approach to determining a fair purchase rate for parallel generation.
- ii. A number of commenters raise concern regarding asymmetry of information and negotiating leverage between an incumbent public utility and a potential parallel generator.
- iii. Another frequent theme is the benefit of consistency in determining the applicable parallel generation pricing, particularly among different public utility companies in Wisconsin, which would lower risk to real estate and other developers willing to scale up and install large units if they could anticipate the financial characteristics associated with investing in parallel generation facilities.
- iv. Another thread that appears across several comments, whether explicitly or implicitly, is the incorporation of externalities into the valuation of parallel generation.
- v. Some commenters express concern about the absence of clear market pricing signals, particularly for valuing capacity and ancillary services.

4. Conclusions

a. Applicability of any one single avoided cost methodology

- No single avoided cost methodology provides precisely accurate values in all situations.
- All established avoided cost determination methodologies have advantages and disadvantages, depending on the relevant circumstances:
 - They apply best to different situations
- The diversity of parallel generation opportunities in Wisconsin is large:
 - Some are already in place and renegotiating purchase rates, some are still in the proposal stage.
 - The scale varies widely.
 - The range of technologies varies as well.
 - The public utility types and their regulatory framework vary.
 - The parallel generation developers also vary.
- The variety of products and services (energy, capacity and ancillary services), and their intrinsic differences, are also relevant to an assessment of their avoided cost.

b. Applicability of MISO's capacity auction mechanism

- MISO's capacity market consists of an annual planning resource auction (PRA) process which is conducted in the beginning of April every year, two months before the beginning of the associated planning year. The PRA is a voluntary residual capacity market where resources that were not used in the fixed resource adequacy plan (FRAP) can be offered during the auction window period. MISO clears these offers based on the needs of the local resource zone (LRZ) and not the size of any resource. Once the offer window closes, the engineering analysis to clear capacity while respecting capacity import and export limits and sub-regional import and export constraints is performed to ensure feasibility of the optimal solution. In April 2020, the PRA for Wisconsin cleared at \$5/MW-Day.
- A few things to consider while using the PRA auction clearing price (ACP) as an indicator for avoided capacity costs:
 - PRA is a voluntary residual capacity market and it is possible for load-serving entities (LSEs) to meet their planning reserve margin requirement (PRMR) without participating in this market.
 - MISO's capacity market does not have a forward capacity requirement, so the ACP is applicable only to the upcoming planning year.

- ACP excludes some charges and benefits seen by the LSE, such as zonal deliverability charges and benefits, and zonal deliverability charge hedges.
- While PRA enforces the resource adequacy requirements, ACP has limitations as a pricing signal for investment in capacity given the year to year volatility in values.
- PRA in the MISO region uses a single requirement vertical demand curve, which leads to high deficiency prices as soon as the market is short and very low prices if the market is long.
- PRA results provide ACP for the entire zone and not by utility which can mean that the ACP value does not match the avoided cost of capacity for a particular utility. For example, if the PRA for a specific zone clears at CONE but a few of the utilities in the zone did not meet their LCR, the net ACP for those utilities will not be CONE. However, they could be estimated based on ACP.

c. Applicability of MISO's CONE calculation

- MISO and its Independent Market Monitor (IMM) together estimate the value of CONE every year for each zone in the MISO region. For 2020, the value is \$257.53/MW-Day. For this calculation they assume the generation unit to be an advanced CT as it provides very high ICAP to UCAP conversion rate (96 percent or higher) and can be constructed in a 2-3 year time frame. They use data supplied by the Energy Information Administration and Bureau of Economic analysis for this estimation. The assumptions used by MISO and its IMM for this estimation are comparable to those used by other RTOs in the development of CONE estimates. The capacity prices in MISO during settlements are capped at CONE in case of inadequate supply to meet demand in each local resource zone (LRZ).
- CONE however, like the peaker method for avoided capacity cost estimation, may not provide an indicator of the value of avoided capacity for every utility. The marginal unit for various utilities under different futures and scenarios might be different based on their energy and capacity positions and other geographical or planning limitations. Renewables like solar generation in many cases can compete with advanced CT technology to provide capacity and shorter timelines from planning to operation.
- MISO's CONE calculation also does not reflect the variety of situations and parameters that may apply to parallel generation capacity. In particular, the scale used for the MISO CONE might not match the scale associated with Wisconsin parallel generation proposals.